BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 92-245-E - ORDER NO. 93-205

MARCH 1, 1993

IN RE: Integrated Resource Plan Filed by South Carolina Electric & Gas Company	))))	ORDER RULING ON INTEGRATED RESOURCE PLAN

I.

INTRODUCTION

In 1987, the Public Service Commission of South Carolina (the Commission) established Docket No. 87-223-E to develop procedures for integrated resource planning by electric utility companies. By Order No. 91-885, issued October 21, 1991, in Docket No. 87-223-E, the Commission adopted integrated resource planning (IRP) procedures after a collaborative process involving the Commission's jurisdictional electric utilities, South Carolina Department of Consumer Affairs, Nucor Steel, South Carolina Energy Users Committee, and the Commission Staff. The procedures were clarified by Order No. 91-1002. On or about April 30, 1992, South Carolina Electric & Gas Company (SCE&G or the Company) filed, pursuant to the IRP procedures, its 1992 Integrated Resource Plan for Commission consideration.

SCE&G's filing was duly noticed to the public, and Petitions to Intervene were received from the following parties: South

Carolina Pipeline Corporation (SCPC), Steven W. Hamm, Consumer Advocate for the State of South Carolina (the Consumer Advocate), South Carolina Energy Users Committee (SCEUC), and Allied-Signal, Inc. (Allied-Signal).

Following a series of collaborative meetings involving SCE&G and the other parties, the parties participating in the Docket and the Commission Staff filed issues lists and prefiled testimony. On September 24, 1992, a Stipulation between SCE&G and the Commission Staff was filed which stipulated certain issues between the Commission Staff and the Company. On October 13, 1992, a Stipulation between SCPC and SCE&G was presented to the Commission.

A public hearing was held in the Commission's Hearing Room commencing at 11:00 a.m., Tuesday, October 13, 1992, the Honorable Henry Yonce, presiding. Belton T. Zeigler, Esquire, represented SCE&G; Sarena D. Burch, Esquire, represented SCPC; Nancy V. Coombs, Esquire, represented the Consumer Advocate; Arthur G. Fusco, Esquire, represented SCEUC; Carolyn C. Matthews, Esquire, represented Allied-Signal, Inc., Metglas Products; and Marsha A. Ward, General Counsel, and F. David Butler, Staff Counsel, represented the Commission Staff.

SCE&G presented the testimony of Joseph M. Lynch and Stephen Eugene Martin. Frederick R. Plett testified on behalf of Allied Signal. The testimony of Nicholas Phillips, Jr. on behalf of SCEUC was stipulated to by the parties.

II.

BACKGROUND

The Commission issued procedures in 1991 requiring the utilities to file Integrated Resource Plans (IRPs). The Commission has jurisdiction to require filing of IRPs by utilities and to require other actions to implement integrated resource planning in South Carolina.

The objective of the IRP process is the development of a plan that results in the minimization of the long run total costs of the utility's overall system and produces the least cost to the consumer, consistent with the availability of an adequate and reliable supply of electricity while maintaining system flexibility and considering environmental impacts. In conjunction with the overall objective, the IRP should contribute toward the outcomes of improved customer service, additional customer options, and improved efficiencies of energy utilization. Order No. 91-1002, supra.

Pursuant to the procedures, each utility must file a detailed 15 year IRP every three years beginning in April 1992. The IRP filing must contain a statement of the utility's long-term and short-term objectives and how these objectives address the overall objective of the IRP process as stated by the Commission. The filing must also indicate how the utility's resource plans seek to ensure that the utility incorporates the lowest cost options for meeting the consumers' electricity needs consistent with the availability of an adequate and reliable supply of electricity.

Some other requirements of the utility's IRP filing include the evaluation of the cost effectiveness of each supply-side and demand-side option, consideration of the environmental costs of the plan, a demand and energy forecast, a discussion of risk assessment associated with the plan, transmission improvements and/or additions necessary to support the plan, evaluation and review of existing demand-side options utilized by the utility as well as discussion of future demand-side and/or supply-side options.

Finally, the IRP procedures require that the Commission review a utility's IRP filing to evaluate the extent of compliance with the Commission's procedures for the specific purpose of determining whether the plan is reasonable at that point in time. The Commission is also to review and determine whether the options selected and incorporated within the IRP are consistent with the Commission's procedures and whether such options have been justified by the utility within its IRP filing. The Commission does not intend to dictate to utility management the specific options that should be adopted as part of the IRP. The utility must maintain responsibility for its performance regarding the implementation of the selected resource options. When the Company seeks to recover its costs, the Commission will determine whether the costs, incurred over time, resulting from implementing each chosen option are reasonable. The Commission may also review the appropriateness of the Company's implementation process for each option. The IRP procedures provide that a utility may file a cost recovery plan with the Commission for approval.

On or about April 30, 1992, SCE&G filed its 1992 IRP with the Commission consistent with the requirements of the Commission's IRP rules. SCE&G's 1992 IRP filing consists of one volume and an Executive Summary.

III.

ISSUES AND EVIDENCE

Based on the testimony, exhibits and evidence received by the Commission during the hearing and the entire record in this matter, the Commission will herein discuss the issues and applicable evidence.

A. Company's Stipulation with Commission Staff

The Stipulation between the Commission Staff and SCE&G was filed as Hearing Exhibit No. 1 in this Docket during the public hearing, which resolves the major issues between SCE&G and the Staff. (Tr. at 6) The Stipulation sets forth the parties' agreement that the Commission Staff has not identified any aspects of SCE&G's 1992 IRP which appear to be inconsistent with the requirements of Order No. 91-1002, issued in Docket No. 87-223-E.

The Stipulation also requires SCE&G to fully justify to the satisfaction of the Commission its overall IRP and the resource options included within the plan. The Stipulation sets forth the parties' agreement on the meaning of a Commission finding of reasonableness regarding the IRP.

The Stipulation also addresses the fact that a plan for recovery of DSM costs will not be addressed in this IRP proceeding, nor will the issue of fuel switching. However, the Stipulation sets forth three criteria that should be met before recovery of DSM costs is appropriate. The Stipulation also incorporates a list of recommendations developed by the Staff and agreed to by the Company to be incorporated in developing the next IRP.

B. South Carolina Electric and Gas Company's IRP

SCE&G's IRP process begins with an Introduction to the Company and the Planning Process. The IRP process then continues with a forecast, demand-side planning, supply-side planning, a financial analysis, and ends with a consideration of other factors, such as environmental planning, transmission and distribution planning, and technology review.

SCE&G presented two witnesses who explained the major components of the Company's plan.

Dr. Joseph M. Lynch, Manager of the Company's Generation Planning Area, presented an overview of the Company's IRP process, and specifically, discussed the forecasting and supply-side planning components of the IRP, as well as the overall net benefits of the Company's DSM programs.

According to Dr. Lynch, the IRP process begins with the development of what the Company calls a reference plan which represents the Company's optimal course of action based on current expectations without modifying planned DSM efforts. To establish a reference plan, the Marketing Department reassesses the system impacts of the existing DSM programs and updates its projections of market penetration. The Forecasting Department gets new economic data from Data Resources, Inc. (DRI), updates its statistical and econometric models, incorporates the updated DSM impacts and produces a new forecast of loads and energy that must be met with supply-side resources. The Generation Planning Department then develops a supply-side plan by choosing an optimal sequence of resources from a menu that includes peaking, intermediate, and baseload generation from owned and purchased resources. The reference plan is then comprised of this combination of demand-side and supply-side resources. Without further modification to the DSM efforts, the reference plan would become the Company's updated IRP.

At this point, demand and energy credits are calculated based on the reference plan and these credits are used by the Marketing Department to evaluate new DSM initiatives. These initiatives would take the form of modifying existing programs and/or instituting new programs. Once the Marketing Department has developed its package of cost-effective DSM initiatives and devised an implementation strategy, then the system impacts of these programs are folded into the forecast and a new supply-side plan is developed. For the 1992 IRP filing, this new supply-side plan became the accepted base case for the IRP.

Dr. Lynch testified that the methodologies used by the Company in forecasting are fairly standard throughout the industry. The long-range energy forecast is made by using statistical time series techniques and multiple regression analysis to relate SCE&G customer and sales growth to various economic and weather variables. Projections of economic variables such as population, personal income and industrial production are provided for the

Company's service territory by DRI which is a well-known economic forecasting firm.

The territorial peak demand, which occurs in the summer, is projected by applying annual load factors to the energy forecast. This calculation is made by customer class. The load factors are then developed with the Company's customer load research data. An adjustment for transmission and distribution losses is embedded in the load factors so that they can be directly applied to the energy sales projections.

Dr. Lynch testified that the Company tested the accuracy of using class load factors to project peak demand and found that the methodology was accurate using an R-squared value or squared correlation coefficient.

All of the econometric models and their parameter estimates as well as the statistical accuracy of these estimates are presented in the Company's 1992 IRP Document along with a more complete discussion of the analyses and studies performed. As a result of the studies, SCE&G expects territorial sales to increase by 2.3% annually over the next 15 years. The residential class will increase by 2.2% per year, the commercial class by 2.8% and the industrial class by 1.6%. The peak demand is expected to increase by 1.8% per year. This represents about a 68 MW increase annually with 23 MW attributable to the residential class, 29 MW to the commercial class, and 4 MW to the industrial class. These energy and demand projections are net of DSM impacts, that is, the Company must develop supply-side resources to meet these customer needs.

With regard to integration of DSM impacts into the forecast, the Marketing Department of SCE&G estimated the cumulative KW and KWH impact of the DSM programs over the planning horizon. For all new programs and for existing load management programs, the full cumulative impact is used to derive the forecast. For existing conservation and efficiency programs, only incremental impacts over 1992 levels are used to adjust the forecast.

With regard to the supply-side plan, SCE&G uses a variety of commercial and custom software products in developing long-range plans. The result of the plan shows that if you combine a 20% reserve margin with a peak demand growth of 68 MW a year, SCE&G's need for capacity is increasing by about 82 MW annually. Over a 15 year period then, there will be a need to add about 1,230 MW of capacity. SCE&G supply-side plan projects an increase of 1,229 MW of capacity which includes the Cope Plant. Dr. Lynch testified that the supply-side plan as presented by SCE&G is very flexible, that the Cope Plant is somewhat of a linchpin around which the rest of the supply-side plan can be shifted with great fluidity, if the demand growth changes. Then the Company could simply avoid the power purchases and/or change the timing of the construction of turbines.

With regard to the overall net benefits of the Company DSM programs, Dr. Lynch testified that without DSM efforts, the Company's peak demand would increase by 96 MW per year instead of 68, capacity requirements would be 41% greater and territorial energy would increase by 499 GWH annually instead of 456 GWH.

Dr. Lynch estimates that the collection of DSM programs save customers of SCE&G $190 million in present-worth revenue requirements over a 15 year period, and this is net of DSM expenses. Under cross-examination by Staff Attorney Butler, Dr. Lynch testified that, the Company estimates the DSM impact on energy to be a reduction of 662 million KWH, and on the demand-side, a reduction of 469 MW in peak demand.

The Company also presented the testimony of Steven Eugene Martin who testified as to the Company's position on demand-side management and portions of the demand-side planning of the IRP. Mr. Martin's overall thrust was that the Company's DSM efforts effectively addressed the objectives of Commission Order No. 91-1002.

Mr. Martin testified that the demand-side management process has undergone significant evolution over the past several years and will continue to be a dynamic process for the foreseeable future. Demand-side management planning integrates a number of qualitative and quantitative steps in establishing the applicability of the technology to meet the Company's resource needs. Mr. Martin testified that four tests are run on each DSM resource option. The first test is the Total Resource Cost Test or TRC, also known as the All Ratepayers Test. This test is a measure of the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers as a whole. The second test is the Participant Test which is a measure of quantifiable benefits and costs of a DSM program from the perspective of a participant. The third test is the Ratepayer Impact Measure Test or RIM, which is a measure of the difference between the change in total revenues paid to a utility and the change in total costs to a utility resulting from a DSM program. The fourth test is the Utility Cost Test which is a measure of the change in total costs to the utility that is caused by the DSM program.

Mr. Martin testified that programs that emerge with positive net benefits and associated benefits/costs are presented to authorities within the Company for approval. After approval, the program is subjected to a formal implementation process for integration into the Company operations. Mr. Martin testified that the final stage of the DSM planning process is a projection of the proposed DSM programs on the Company's resource plans. Mr. Martin testified that the Company has invested over $18 million in DSM efforts over the past 5 years, and has increased its labor commitment to the DSM by over 200%. Mr. Martin further testified that demand-side management is still evolving in terms of practice, methods, evaluation tools and effective measurement. Mr. Martin states that there are impact risks and marketing acceptance risks with DSM programs. Therefore, the Company must deliberately build the body of knowledge and resources that represents the natural progression of existing technology. Mr. Martin testified that methodology has changed and evolved over the past 5 years, and that SCE&G is embarked on a number of efforts to strengthen its DSM capabilities, including increasing staff and field sales resources, soliciting expert third party assistance and pilot tests of alternative technologies.

Mr. Martin summarized his testimony by stating that SCE&G is fully committed to DSM as a viable means to meet its customers' future energy needs. Martin stated the Company has made a determined effort to develop and implement a comprehensive and effective DSM program.

Frederick R. Plett, represented Allied-Signal, Inc. Mr. Plett testified that his purpose was not to criticize SCE&G, but rather to discuss the value of "positive regulation." He further testified that amorphous metal distribution transformers (AMDTs) could provide benefits to electrical customers in South Carolina and that the Commission should encourage economic utility investments. According to Mr. Plett, amorphous metal transformers significantly reduce core losses when compared to silicon steel core transformers. Generally, the more efficient the transformer the higher the purchase price. The appropriate test is to compare total owning costs of transformers. Mr. Plett proposed the use of A and B factors in calculating the "total owning costs." On cross-examination, Mr. Plett indicated that he was aware that SCE&G is presently utilizing amorphous core transformers on its system.

The parties stipulated to the testimony of Nicholas Phillips, Jr., who testified on behalf of the South Carolina Energy Users Committee. In summary, Mr. Phillips testified that utilities in South Carolina, including SCE&G, have engaged in conservation and load management programs for at least 10 years. Mr. Phillips testified that the Commission should be aware that SCE&G data indicates that its rates would be lower without DSM for the next 10 years. However, SCE&G forecasts lower rates with DSM over the very long term under the assumption that its DSM efforts will be successful. Mr. Phillips further testified that approval of the IRP should in no way pre-approve supply-side or demand-side expenditures. According to Mr. Phillips, the Commission should not get involved in the utility decision-making process. The responsibility for decision-making rests clearly with SCE&G. Further, Mr. Phillips testified that an IRP proceeding should not include utility ratemaking. Cost-recovery is not an appropriate subject for an IRP, according to Mr. Phillips.

IV.

FINDINGS AND CONCLUSIONS

Based upon consideration of the foregoing, the Commission makes the following findings of fact and conclusions of law:

A. STIPULATION BETWEEN SCE&G AND THE COMMISSION STAFF

The Stipulation between SCE&G Company and Commission Staff addresses several major issues of SCE&G's IRP filing. The Commission agrees with most aspects of the Stipulation, and the Commission approves this Stipulation, except as discussed below. Consistent with the Stipulation, the Commission finds that SCE&G's 1992 IRP is consistent with the South Carolina IRP procedures set forth in Order No. 91-1002 in Docket No. 87-233-E. However, this finding does not constitute either pre-approval of costs or prudency for full cost recovery for the resource options included in the IRP, as is stated in the Stipulation.

The Commission finds that it does not fully concur in Paragraph 6 of the Stipulation. The language dealing with the resource options in Paragraph 6 should read as follows, in order to more appropriately state the Commission's view:

> With regard to the resource options incorporated within the plan, a Commission finding of reasonableness means: a) that the resource options included within the plan should satisfy the projected energy requirements of the Company's customers given current information and assuming proper implementation; b) the Commission will monitor the costs incurred in the implementation of each option as to the reasonableness and prudence over time and will monitor the implementation process as to its appropriateness.

Thus, a finding of reasonableness by the Commission indicates that the Commission believes that the Company made a good faith effort to comply with the established procedures and the objective statement of Order No. 91-1002. A finding of reasonableness does not constitute either pre-approval of costs or prudency for full cost recovery for the resource options included in the IRP.

Paragraph 7 of the Stipulation deals with recognizing that a cost recovery plan for recovery of costs incurred from implementing DSM programs is not to be considered within this IRP proceeding before the Commission. In this case, the Commission agrees. A stated plan for cost recovery may be outlined in a future rate case, as further stated by SCEUC.

While the Commission finds that the language of Paragraph 8 would normally be appropriate, this Commission believes that the following language should also be added to Paragraph 8 of the Stipulation to better state the Commission views:

> The appropriateness of the full costs related to the resource options will be determined during future proceedings. Resource cost recovery must be consistent with existing procedures for supply-side options while DSM options must comply with the procedures set forth through the IRP process. The IRP process established by Order No. 91-1002 was not intended to modify the existing regulatory procedures already established for supply-side options. Thus, existing supply-side options already in service or under contract are treated as given for purposes of the Commission's evaluation of the plan. The IRP process was designed in part to encourage consideration of DSM options by establishing a mechanism to evaluate and incorporate such options within the utility planning process.

Paragraph 9 sets forth the criteria that SCE&G must meet before it may recover DSM costs. The specific details for any cost recovery mechanism for the utility will be determined at some future point in time. It is the utility's burden to justify the cost-effectiveness of each DSM resource option in its IRP. The Stipulation sets forth the criteria the Company must include to justify the DSM options.

When DSM cost recovery is considered, the following three criteria should be met before recovery of such costs is appropriate by the Company:

> a. Justification of each DSM resource option by the utility as to its cost effectiveness. The Staff's position is that the utility must justify each option in its IRP. Justification would include establishing the cost effectiveness of the option using an appropriate method of analysis. Justification of the resource option to the satisfaction of the Commission would mean that it is appropriate to incorporate the

option within the IRP. It should be noted that the cost-effectiveness screening of the DSM options is based largely on estimated and projected costs and benefits. Thus the requirements for b and c must be met.

b. Justification of reasonableness and prudent implementation costs incurred through an appropriate implementation process must be shown by the utility. For DSM options, the utility must justify the implementation process which it followed for each option and must justify any costs which exceed the levels projected for the option. The utility must contrast the projected costs and the actual costs and must justify any costs in excess of the projected amount incorporated within the cost-effectiveness analysis.

c. Demonstration that the level of benefits achieved from the option is consistent with the approved IRP. The DSM option must be shown to have achieved an appropriate level of benefits. The utility must contrast the projected benefits with the actual benefits achieved and explain any failure to achieve the estimated benefits. The utility must justify to the Commission the failure to meet the projected level of benefits and justify the costs associated with the option. The failure by the utility to achieve the projected level of benefits does not mean that the direct costs of options are not recoverable (the level of any reward or incentive might be impacted by the level of accomplishments assuming that such a mechanism is adopted and depending upon the type of incentive mechanism that is adopted by the Commission).

The Commission has considered the provisions of the Stipulation and finds that it is appropriate for the Company to follow the requirements contained within the Stipulation Paragraph 9 as set forth above before cost recovery may be allowed by the Commission. Therefore, the provisions of Paragraph 9 are approved as set forth in this Order.

The Commission has considered the language of Paragraph 12 of the Stipulation regarding fuel switching. The Commission agrees that it is not necessary to address the impact of fuel switching on other energy suppliers in this docket at this time. The Commission is of the opinion, that it is more important to get the electric utilities to implement their respective IRP's and proceed with this process than to introduce another element which is, at this stage, controversial, uncertain and complex. At this point in time, electric utilities should not be required to consider natural gas DSM options. The Commission will continue to monitor the issue.

B. SCE&G'S IRP

SCE&G's IRP process has established a resource mix, including appropriate DSM programs, which maintain the necessary flexibility to meet projected energy and demand. The resource mix is found to be reasonable by the Commission. The forecast used for the 1992 IRP is reasonable given current information. SCE&G's demand-side, supply-side, and purchased resource planning processes are reasonable. SCE&G's integration process is appropriate and results in a reasonable integrated resource plan.

The Commission would, however, like to address SCE&G's DSM impact measurement plan. We believe that the Company should make every effort to refine the process of estimating DSM impacts so as to properly verify energy savings achieved toward these DSM Programs and also identify the projected durability of such savings over time. SCE&G should address in future IRP's and Short-Term Action Plans (STAP's) upgrading the engineering estimate process currently used to develop such estimates, including consideration of any possible snap back effects, free riders, consumer tastes impacting usage under an option, errors resulting from modeling assumptions, and laboratory experiments which do not reflect current realities in the specific areas. A formal plan shall be filed with the Commission for its consideration pertaining to this issue no later than with the Company's 1994 Short-Term Action Plan filing.

The Commission notes that there are numerous views on the proper method to address environmental externalities. SCE&G testified that it includes the cost of environmental compliance in the assessment of resource options and qualitatively considers environmental effects in resource assessments. The Commission finds this is a reasonable approach at this time and consistent with Order No. 91-1002, but will continue to monitor the issue.

SCE&G considers utility and non-utility generators including qualifying facilities under PURPA and independent power producers. Based on the evidence, the Commission finds that SCE&G purchased resource planning process is appropriate and reasonable at this time. However, this issue will be addressed in future IRP related proceedings. The Company should file any purchased power evaluation procedures that it has developed no later than the Company's 1994 Short-Term Action Plan filing.

The Commission further finds that SCE&G should continue to pursue power delivery efficiencies, such as amorphous metal transformers, where such is cost effective.

The Consumer Advocate, through its cross-examination of the Company witnesses, and its post-hearing brief, implies that SCE&G's DSM options process is biased against conservation options. The Stipulation between the Commission Staff and SCE&G encourages conservation. The Commission hereby strongly encourages the Company to review and pursue said conservation options which are shown to be cost effective and consistent with the IRP procedures.

All in all, however, the Commission concludes that SCE&G's IRP is consistent with the Commission's stated objective for the IRP process and the Company has made a good faith effort to comply therewith. Based upon the information available at this time, SCE&G's IRP is appropriate and reasonable to meet the needs of its electric customers in an economical, efficient and reliable manner.

C. PROCEDURE FOR FILING NEW, MODIFIED[1] OR PILOT DSM PROGRAMS

Although the parties could not agree in this proceeding on a procedure for the filing and evaluation of new, modified or pilot DSM programs, the Commission believes that it should establish at least a procedure by which the Company may file with the Commission Staff information on new, modified or pilot DSM programs. The overriding concern of the Commission is that the Staff be given the necessary information in a timely manner, so that it will have an understanding of new or modified programs. Therefore, the Commission takes judicial notice of Order No. 93-8, dated January 25, 1993 in Docket No. 92-208-E, Application of Duke Power Company for an Integrated Resource Plan. Attached to that Order was an Appendix which contained filing requirements for interim DSM programs. This Commission adopts these filing requirements for this Docket, and these are attached hereto as Appendix A, and are incorporated herein. These may be modified from time to time by the Staff. We hereby specifically hold in abeyance the establishment of a procedure to deal with these interim filings until some future time.

D. FURTHER FINDINGS AND CONCLUSIONS

1. In developing its next IRP, the Commission orders SCE&G:

a. To maintain an appropriate portfolio of DSM programs with special consideration of cost-effective energy efficient options, conservation options and peak reducing options;

b. To make use of pilot projects where feasible and appropriate to evaluate major uncertainties related to DSM options. Such pilot projects should seek to include

1. "Modified" includes the elimination of a DSM option.

end-use analysis where feasible and cost justified with emphasis on the identification of market barriers and the resolution of such barriers;

c. To seek to develop joint pilot projects with other utilities to share costs and benefits;

d. To pursue actively end-use analysis to gain further insight into consumer behavior where feasible and cost justified;

e. To seek to ensure that optimum results be attained from all energy audits conducted by or for the Company;

f. To seek to attain an optimum level of operating efficiency from its supply-side options consistent with the Commission's Order No. 91-1002;

g. To undertake to develop a methodology for measuring the impacts of DSM options that is cost effective, comprehensive and reasonable;

h. To explore actively and evaluate new DSM technologies and programs;

i. To establish an accounting mechanism or process evaluation which will enable the Commission Staff to adequately track all DSM direct costs and properly identify any lost revenues which the Company plans to recover; and

j. To address issues "a" through "i" within its next two STAP's and the next IRP.

2. The Commission finds that it is appropriate to use multiple tests to determine the cost-effectiveness of DSM options in the IRP process in order to comply with the South Carolina IRP procedures. The Commission finds sole reliance on any one test to evaluate all DSM options is inconsistent with the South Carolina IRP procedures. (See B.6 of the Appendix to Commission Order No. 91-1002).

3. The Commission finds that the IRP procedures, as set forth in Order No. 91-1002, do not require electric utilities to

monetize externalities. Section B.8 of the Appendix to that order sets forth the Commission's requirements regarding environmental and other costs.

4. The Commission takes note of the Stipulation between SCPC and SCE&G, but does not find it necessary to approve or disapprove it at this time.

5. The Company should file with future IRP's the methodology used to develop its avoided cost numbers with an explanation and example.

6. The utility should expand its efforts to obtain useful customer information within the IRP process.

7. That this Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Henry G. Yonce
Chairman

ATTEST:

Charles W. Ballentine
Executive Director

(SEAL)

FILING REQUIREMENTS FOR INTERIM DSM PROGRAMS

a. Description of program
b. Specific program objectives
c. Description of targeted sector
d. Program service life
e. Total market potential (number of potential customers or other relevant measure)
f. Expected saturation to be achieved, including anticipated market growth throughout the life of the program.
g. Summer/Winter expected on-peak demand change per unit (customer, etc.)
h. Annual energy change per unit.
i. Calculation of any estimated lost revenues. Explain how such lost revenues were determined.
j. Calculation of any <u>net lost revenues</u> resulting from the option which are to applied to the deferred account or will be sought in any way for recovery.
k. Magnitude of expected load shape impacts (kw/kwh). Sources of expected load shape impacts. Identify the type of program such as peak clipping, valley filling, conservation, load shift or other. Describe the method used to estimate potential impacts
l. Total program cost estimates on a present worth basis (itemized and quantified) [Annual data may be provided upon request].
m. Total program benefit estimates on a present worth basis. (itemized and quantified) [Annual data may be provided upon request].
n. Sources of cost/benefit data
o. $/kw saved and $/kwh saved
p. Test results including:
    i. utility cost test results
    ii. total resource cost test results
    iii. rate impact measure test results
    iv. other tests necessary to evaluate the program
q. Explain which test(s) were most appropriate to evaluate the option and why
r. Customer/vendor incentives expected to be paid, their purpose and how the incentives were derived
s. Itemized proposed charges to DSM deferred account over the life of the program
t. Other known expenses itemized over the program life
u. Calculation of any proposed rewards to be obtained by the Company
v. Proposed program evaluation methodology-including planned load research methods.
w. Marketing strategies-including examples of any marketing media to be employed
x. Potential program problem areas considered.